UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

OFFICE OF THE
INSPECTOR GENERAL

July 21, 2017

MEMORANDUM TO: Concur: Case Closed
(b)(7)(C)
Joseph A. McMillan
Assistant Inspector General
for Investigations

THRU: (b)(7)(C)
Team Leader, (b)(7)(C)

FROM: (b)(7)(C)
Special Agent, (b)(7)(C)

SUBJECT: FAILURE TO IDENTIFY POTENTIAL PROBLEMS WITH A SAFETY RELIEF VALVE DURING A COMPONENT DESIGN BASES INSPECTION AT PILGRIM NUCLEAR POWER PLANT (OIG CASE NO. 15-029)

Allegation

The Office of the Inspector General (OIG), U.S. Nuclear Regulatory Commission (NRC), conducted this investigation to assess the adequacy of NRC's June 2014 Component Design Bases Inspection (CDBI) at Pilgrim under Inspection Procedure (IP) 71111.21. Seven months after this CDBI, in January 2015, a Safety Relief Valve (SRV) failed to open on operator demand during mitigation efforts for a Loss of Offsite Power (LOOP) event affecting the plant. A subsequent Special Inspection Team (SIT) found that the SRV in question was inoperable. In addition, that SIT found that a second SRV, which had been inspected during the 2014 CDBI, had been inoperable since experiencing an earlier, similar failure to operate in February 2013. That period of inoperability included the time period during which the 2014 CDBI was conducted.

Potential violations relevant to this investigation include IP 71111.21, "Component Design Bases Inspection," and 5 CFR 2635, "Basic Obligation of Public Service."

Findings

OIG did not substantiate that the failure to detect the inoperability of the SRV reflected a failure by NRC staff to conduct the 2014 Pilgrim CDBI consistent with the requirements of the then current revision of IP 71111.21. The prolonged inoperability of the SRV was attributed to the licensee's interpretation of the valve's February 2013, failure to open as an instrument problem rather than a problem with the valve itself. The particular licensee condition report documenting the February 2013, failure to open was not sampled during the 2014 CDBI, and was not specifically required to be sampled under IP 71111.21. However, given the history of issues with the SRVs at Pilgrim, the CDBI team's non-selection of that condition report for review was identified by two NRC subject matter experts on CDBI procedures and practices as a potential missed opportunity to address the condition.

Basis for Findings

Inspection Reports

OIG reviewed the NRC CDBI inspection report, dated July 16, 2014. The inspection included "18 components and 4 operating experience samples." OIG noted that this met the requirement in the then current IP 71111.21 for 15 to 25 samples to be included. One such selected component was the SRV designated "RV-203A," hereinafter referred to as the "A" SRV. The report summarizes inspection steps taken, including walkdowns, interviews with operators and engineers, and reviews of design documents. Specifically regarding the "A" SRV, the CDBI team reviewed licensing and design basis documents, the vendor manual, corrective action documents, system health reports and reports of testing and surveillance on the component, including "surveillance procedures, emergency operating procedures, and SRV test results to determine whether the valve's relief capacity was consistent with the design assumptions to depressurize the reactor vessel during design basis accident conditions, and whether test result acceptance criteria enveloped design basis limits." No findings were identified.

OIG's analysis of the CDBI report noted that consistent with IP 71111.21 requirements, the inspection documented a Design Review, Review of Maintenance Areas, and Review of Problem Identification and Resolution Area for the SRV in question. Appendix 1 of IP 71111.21 identifies 14 attributes, which are individual design related features or measures relating to a given component, to be considered for sampling

during an inspection. The inspection report documented that 8 of the 14 attributes identified in Appendix 1 were sampled for the SRV. Not all attributes are required to be sampled.

OIG also reviewed the subsequent NRC SIT report, dated May 27, 2015, in which Region I inspectors reviewed the January 27, 2015, LOOP event as well as other related occurrences at the plant, including one in which another SRV, designated as the "C" SRV, failed to open on operator demand with the system at low pressure. The report documents a preliminary white finding related to the respective failures of both the "A" and "C" SRVs. According to the report, the licensee had incorrectly attributed the "A" SRV's February 2013, failure to open at low pressure during a similar LOOP event to a defective instrument, an acoustic monitor that signals operators when the valve is open. The licensee had also incorrectly concluded that the "A" SRV had actually opened in February 2013, because of a rise in the tailpipe temperature. Because of this, the licensee did not test or repair the internals of the "A" SRV itself, which the 2015 SIT found to contain wear and damage that interfered with its on-demand opening function. The "C" SRV contained similar wear and damage, and so the SIT attributed the 2015 failure of the "C" SRV to open in part to the licensee's prior failure to correctly identify and address the earlier problem with the "A" SRV in the immediate aftermath of the similar February 2013, incident. The SIT indicated that both SRVs were inoperable as of January 2015, and therefore, the "A" SRV "was inoperable for greater than its Technical Specification allowed outage time." The report also documented that both the "A" and "C" SRVs were replaced subsequent to the January 27, 2015, event.

Further, the SIT report documented that in following up to the January 2015 incident, the team reviewed a licensee condition report (CR), identified as CR-PNP-2013-00825, documenting the February 2013, incident. This CR discussed the acoustic monitor and SRV tailpipe temperature responses to the operator actions, but did not address several other plant parameters that are normally used to verify an SRV opening, such as reactor vessel pressure and water level. The only action that resulted from the 2013 CR was the replacement of components associated with the "A" SRV's acoustic monitor. The CR was closed based on a purportedly defective acoustic monitor, because the licensee concluded that the SRV had opened due to instruments detecting a tailpipe temperature rise the licensee interpreted to be consistent with the SRV opening. The 2015 SIT inspectors found that the temperature rise was in fact too low to be consistent with an opening of the SRV, that the licensee's attribution of the issue to an acoustic monitor problem was incorrect, and that the SRV had in fact failed to open. The SIT inspectors documented that the licensee also did not properly take into account a lack of pressure drop in the reactor vessel and a lack of reactor vessel water level swell, both of which would be consistent with a failure to open. OIG learned that CR-PNP-2013-00825 was not reviewed by the 2014 CDBI team, although other CRs were reviewed among the attributes of the "A" SRV sampled during the CDBI.

Interview of (b)(7)(C)

When interviewed, (b)(7)(C) a Region I Reactor Inspector who not only served as the CDBI (b)(7)(C) at Pilgrim in 2014, but also was a team member for the SIT following the 2015 LOOP event, was asked how, from the perspective of a stakeholder, the CDBI could have properly inspected a component later found during the SIT to have been inoperable. (b)(7)(C) noted that operability of the SRV would require both the capability to function by automatically opening to relieve excessive pressure at high pressures of approximately 1000 pounds per square inch (PSI), and the capability to open manually on operator demand to control pressure during operations such as a controlled shutdown, which could occur at pressures as low as 100 PSI. Operability for the SRV would require its availability throughout the pressure range, but the more safety significant function was high pressure automatic opening. (b)(7)(C) stated that this model of valve can experience pressure leakage at the "seat," where the valve actually seals to achieve pressure control, or at the pilot valve, which operates the main valve. Leakage of these two kinds had been a known problem at Pilgrim and industry-wide in the past, and this had led the team to focus on conditions relating to such leakage during the CDBI, rather than on conditions that could interfere with low pressure opening upon operator demand. (b)(7)(C) said that after the 2015 event, the two inoperable SRVs were removed from the plant and tested in as-found condition at the manufacturer's test facility, and this "bench testing" disclosed that the Pilgrim SRVs had experienced abrasion and wear on the contact surfaces of the valve internal surfaces that may have added friction, thereby preventing opening of each SRV at low pressure. He stated that at high pressure, both SRVs did successfully operate. He also confirmed that Pilgrim was operating at the time of the 2014 CDBI, which would have precluded the CDBI team from including within its inspection scope the kind of bench testing and examination of internals that later disclosed the internal wear and abrasion.

Regarding the condition report, numbered CR 2013-00825, pertaining to the "A" SRV, (b)(7)(C) confirmed that as documented in this CR, the licensee's 2013 follow-up to the identified "A" SRV problem had resulted in their attributing the problem not to the valve's failure to open but to a problem with the valve's acoustic monitor. (b)(7)(C) also confirmed that, although he had later become aware of this CR during the 2015 Special Inspection, it was not reviewed in the course of the 2014 CDBI. He said that this CR was not selected because of the random nature of sampling, albeit "informed" random sampling, used in the CDBI. He elaborated further that "we're supposed to evaluate, look at the list of CRs and pick the ones that we think have some risk or safety impacts." According to (b)(7)(C) the challenge with the sampling process is that selection is frequently done using the CR title and number as it appears on the list, which may not clearly convey the true nature of the issue.

Interview of (b)(7)(C)

(b)(7)(C) (b)(7)(C) Reactor Inspector, told OIG that he participated in the 2014 CDBI at Pilgrim. He confirmed that his tasking was (b)(7)(C), and that his individual tasking specifically included the SRVs, and more specifically the "A" SRV. He said he understood why a stakeholder might see the non-detection of the issue in the CDBI as a problem. He had also questioned whether and why he had not reviewed the CR referencing the 2013 failure to open of the "A" SRV. (b)(7)(C) said he did not know why he had not selected the particular CR. He was uncertain whether it was on the list of CRs provided by the licensee, which is usually indexed to a component ID or the keywords naming the component. He said it was possible that even if it was on the list, his review of the brief description in a listing would not have resulted in its selection. OIG advised (b)(7)(C) that the description emphasized the acoustic monitor rather than the component itself. (b)(7)(C) confirmed that the IP does not require selection of every CR for a given component, because it is a sampling inspection. He estimated that a component would typically yield a list of 20-30 CRs, and inspectors would then select samples based on the CR description.

(b)(7)(C) said that operators frequently use two parameters to identify SRV function, the acoustic monitor and tailpipe temperature. (b)(7)(C) was aware that the Pilgrim operators did not get the acoustic monitor response for opening but did get a tailpipe temperature response that they called satisfactory at the time. (b)(7)(C) said that during a recent, 2016 Supplemental Inspection at Pilgrim also covering the SRVs, in which he also participated, additional data contained in pressure and temperature charts or "traces" from the 2013 failure was reviewed and showed that the tailpipe temperature in 2013 had not been high enough to be consistent with opening, and that other data had not been consistent with proper opening. (b)(7)(C) stated that although there was a difference in the safety and risk significance of low and high pressure SRV operation, he treated all components and attributes "all the same" in selection and inspection because operability was the issue. (b)(7)(C) stated that the licensee error in interpreting tailpipe temperature associated with the SRV incorrectly was not known at the time of the CDBI, and if it had been known it could have led to further review of the SRV and a possible finding. He suggested that reviewing trace data for components as a regular part of a CDBI or similar component inspection would be something he would personally do consistently, and might be a suggestion he would make for a potential new procedural requirement to prevent this type of occurrence in the future.

Interview of (b)(7)(C)

(b)(7)(C) (b)(7)(C) (b)(7)(C) Reactor Analyst, stated that he was involved with consultation and peer review for the risk assessment on the Pilgrim SIT. He recalled that both SRV failures were at very low pressure, but confirmed that for operability, the SRVs had to be operable at any point within a range of approximately 50 to

approximately 1300 PSI. (b)(7)(C) confirmed (b)(7)(C) account of the internal abrasion revealed by manufacturer bench testing after the January 2015, incident. He also confirmed (b)(7)(C) account that the tests showed both SRVs would fail at 100 PSI, but functioned or would function at all pressures above approximately 200-220 PSI. (b)(7)(C) stated that the SRVs were thereby "inoperable but functional" in that they could open on operator demand or automatically in response to a high pressure transient above 220 PSI of pressure.

(b)(7)(C) who was also an experienced CDBI inspector and team lead, said that in his view, during the CDBI the licensee should have been asked about any prior LOOP events and about the operation of the SRVs during those events, because any such operation of the SRV would represent "out of normal" plant conditions. According to (b)(7)(C) the team lead should have obtained more detailed information about the SRVs including CR PNP-2013-00825. He did, however, acknowledge that substandard licensee handling of CRs could also have been a factor in this CR's non-selection, because he knew from participating in the 2016 Supplemental Inspection at Pilgrim that Pilgrim CRs had often been found to lack clarity in wording, title and description, particularly regarding operability. Regarding the CDBI team overlooking the CR or other SRV relevant data, (b)(7)(C) said that based on his extensive experience, rather than exclusively focusing on CRs, it would be more effective to rely on obtaining and reviewing the traces for the given components, which would provide complete raw data on component performance from the plant process computer. (b)(7)(C acknowledged that given the wide range of specifications for operability, he as a CDBI team leader would typically tell his inspectors that "I want you to look at the highest risk piece of this component. He said that the "low pressure function is not as risk significant." However, he said that "a failure is a failure."

Interview of (b)(7)(C)

(b)(7)(C) (b)(7)(C Reactor Operations Engineer and (b)(7)(C) (b)(7)(C) and subject matter expert for CDBI inspections across the Agency, told OIG that he learned of the white finding from the SIT, and thought, "that sounds like something we should have identified in a CDBI." (b)(7)(C) noted that the failure involved a particular CR closed by the licensee on what proved to be an incorrect basis, i.e., the acoustic monitor fault, and that the Pilgrim SRVs had a previous history of failure such as the February 2013, failure to open. Because of this, in (b)(7)(C view, the CDBI team should have placed added emphasis on the maintenance history of the component, and that best practices for the CDBI would include an emphasis on such maintenance history in sampling, and this emphasis would ideally be reflected in the IP requirements. He pointed out, however, that the process remained dependent on individual inspector skills and experience.

Because OIG identified a potential missed opportunity by the NRC CDBI inspection to review the condition report, OIG AIGI is providing a copy of the closing memorandum to OIG AIGA as part of a suggestion to more broadly review the CDBI process. Accordingly, it is recommend that this case be closed to the files of this office.

Distribution:
Case File 15-29

Magnum

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September 22, 2016

Concur: Case Closed
Joseph A. McMillan
Assistant Inspector General
for Investigations

MEMORANDUM TO:

THRU: (b)(7)(C)
Team Leader, (b)(7)(C)

FROM: (b)(7)(C)
Special Agent, (b)(7)(C)

SUBJECT: NRC MANAGEMENT DIRECTED STAFF NOT TO ISSUE REQUEST FOR INFORMATION PERTAINING TO FINANCIAL ASSURANCE FOR OPERATION COSTS (OIG CASE NO. 14-011)

Allegation

The Office of the Inspector General (OIG), Nuclear Regulatory Commission (NRC), conducted this investigation in response to a November 14, 2013, allegation from U.S. Senators (b)(7)(C) and (b)(7)(C) that on June 5, 2013, NRC Office of Nuclear Reactor Regulation (NRR) technical staff were prevented from issuing a Request for Additional Information (RAI) to Entergy, an NRC licensee, in connection with the financial condition of its nuclear plants (Pilgrim Nuclear Power Station in Massachusetts, Vermont Yankee in Vermont, Indian Point Energy Center and the James A. Fitzpatrick Nuclear Power Plant in New York, and Palisades Plant in Michigan). In addition, it was alleged that the same NRC staff were directed to refrain from issuing financial RAIs to any licensee that is currently subjected to additional safety oversight because of safety problems at the reactors.

It was also alleged that this direction to staff (refrain from issuing financial RAIs) was contrary to direction provided by then-NRC Chairman Allison MACFARLANE to issue the RAIs and that (b)(7)(C) Deputy Director, NRR, Division of Inspection and Regional Support (DIRS), disagreed and said that the Chairman "is only one Commissioner."

Potential violation relevant to this allegation is 5 CFR 2635.101 – Basic Obligation of Public Service.

Findings

OIG could not substantiate impropriety in NRR's direction to staff not to issue financial related RAIs to licensees, or that Entergy, an NRC licensee, improperly influenced NRR to make that decision.

OIG found that on June 6, 2013, NRR (b)(7)(C) with support from his managers, directed NRR staff to refrain from issuing financial RAIs until the process for issuing this type of request could be better defined and documented. OIG learned that most RAIs are issued by NRC when the staff is reviewing proposed licensing actions and needs additional information from the licensee to make a decision, and that there is a well-defined process for licensing-related RAIs. However, the financial RAIs that were halted by the NRR (b)(7)(C) were unrelated to any licensing action, and it was not clear to the (b)(7)(C) or his managers what would be done with responses from the licensee. OIG also learned that NRR issued two financial RAIs in the 3 months preceding the decision to postpone further RAIs; however, these were not reviewed by the NRR (b)(7)(C) who had been on rotation at the time. OIG further determined that although an Entergy representative telephoned the (b)(7)(C) manager on July 6, 2013, to express a concern about a draft RAI and request a "drop-in" meeting on June 11, 2013, to discuss the matter, the (b)(7)(C) had documented his concerns clearly and shared them with his managers prior to this contact.

Although the decision to put the RAIs on hold was made after the phone call, and NRC managers recognized the licensee was questioning the process for the financial RAIs and the potential impact on their operations, the managers maintained that their decision to halt the RAIs was not improperly influenced by licensee pressure. Rather, they halted the RAIs after the phone call due to their own concerns about the lack of process, and the "drop-in" meeting did not impact that decision.

OIG found that in March 2015, NRC finalized guidance to staff describing NRC's authority for requesting financial information from licensees and various process aspects, including criteria to determine whether RAIs should be issued, criteria for

evaluating information provided by licensee, and closeout and disposition following staff analysis of licensee responses to financial RAIs. It wasn't until July 2016 that NRR staff evaluated the 2013 RAIs using the new guidance and concluded no further action was required on the RAIs, which are now considered closed by the staff. This information was received July 8, 2016, pursuant to OIG continuous request for finalization by NRR of the issue.

OIG found that former NRC-Chairman MACFARLANE did not recall making a statement to staff to issue the RAIs and that she was aware such direction would have needed to come from the Commission.

Basis of Findings

Background

Decommissioning is the safe removal of a nuclear facility from service and the reduction of residual radioactivity to a level that permits release of the property and termination of the license. NRC rules establish site-release criteria and provide for unrestricted and, under certain conditions, restricted release of a site. NRC also requires all licensees to maintain financial assurance that funds will be available when needed for decommissioning.

Each nuclear power plant licensee must report to the NRC every 2 years the status of its decommissioning funding for each reactor or share of a reactor that it owns. The report must estimate the minimum amount needed for decommissioning by using the formulas found in 10 CFR 50.75, "Reporting and recordkeeping for decommissioning planning." Licensees may alternatively determine a site-specific funding estimate, provided that amount is greater than the generic decommissioning estimate. NRC staff perform an independent analysis of each of these reports to determine whether licensees are providing reasonable "decommissioning funding assurance" for radiological decommissioning of the reactor at the permanent termination of operation.

Per 10 CFR 50.33(f)(5), NRC may request that a currently operating reactor licensee provide information regarding its financial arrangements and status of funds. Specifically, the Commission may request an established entity or newly-formed entity to submit additional or more detailed information regarding its financial arrangements and status of funds if the Commission considers this information appropriate. This may include information regarding a licensee's ability to continue the conduct of the activities authorized by the license and to decommission the facility.

Consistent with NRC staff guidance in NUREG-1577, "Standard Review Plan on Power Reactor Licensee Financial Qualifications and Decommissioning Funding Assurance," NRC does not systematically conduct ongoing reviews of financial qualifications or financial conditions of licensees. However, NRC staff conduct ongoing reviews of all licensees by screening trade papers, industry newsletters, and various public sources for business, finance, and economic news to determine whether there is a need for additional information.

One method available to NRC for seeking information from licensees is through an RAI. RAIs are typically issued by NRC when the staff is reviewing proposed licensing actions and needs additional information from the applicant. According to an NRR Handbook, the need for additional information relative to a particular licensing action or activity may be identified by the project manager (PM), but generally such a need is identified by the technical branch reviewer. In the latter case, the technical branch reviewer prepares the questions seeking the information and forwards the questions by memorandum to the PM. The PM reviews the questions and discusses any proposed modifications with the originator. The PM then prepares a letter to the affected organization with instructions for responding. The NRR Handbook notes that it may be helpful to discuss the pending RAI with the organization prior to forwarding the letter to settle on a mutually agreeable response schedule.

Chronology

On March 20, 2013, NRC issued an RAI to Entergy pertaining to information provided on Entergy's quarterly 10-K[1] Securities and Exchange Commission (SEC) filing about its Vermont Yankee Nuclear Power Plant. The RAI asked the licensee to provide more detailed information to support NRC's financial qualification review. The RAI had been drafted by (b)(7)(C), a (b)(7)(C). OIG learned that in addition to drafting the RAI, (b)(7)(C) concurred on the draft as (b)(7)(C).

(b)(7)(C) provided the draft RAI to (b)(7)(C) the (b)(7)(C) (b)(7)(C) and (b)(7)(C) coordinated with the plant (per process) by letting the plant know in advance the RAI would be coming and asking them to contact NRC if they had any concerns.

On April 4, 2013, NRC issued an RAI to Luminant Generation Company, LLC, with questions pertaining to information provided on the company's annual 10-K SEC filing

[1] The annual report on Form 10-K provides a comprehensive overview of the company's business and financial condition and includes audited financial statements. After it is filed, 10-K information is made available via the SEC Web site.

with regard to the Comanche Peak Nuclear Power Plant. The RAI was drafted by (b)(7)(C) and provided to (b)(7)(C), the (b)(7)(C). This time, (b)(7)(C) as acting DIRS (b)(7)(C), concurred on the draft.

On May 2, 2013, Luminant provided its response to NRC pertaining to Comanche Peak and the response discussed the company's internal restructuring of Energy Future Holdings Corporation. After reviewing this response, (b)(7)(C) communicated with Region IV and a "focus inspection" was conducted at the plant to determine if financial issues created safety problems. The inspection determined everything was in alignment at the plant. (b)(7)(C) wrote a safety evaluation and a closeout letter was sent to the licensee on January 28, 2014.

On May 6, 2013, Entergy responded to its RAI with financial projections for the next 5 years. After reviewing this information, (b)(7)(C) was concerned about the financial data and its potential impact on other Entergy plants so she prepared a followup RAI and requested approval from (b)(7)(C) (b)(7)(C), DIRS.

On May 31, 2013, (b)(7)(C) sent a detailed email to (b)(7)(C), (b)(7)(C) DIRS, and (b)(7)(C) (b)(7)(C) DIRS, discussing financial qualifications for operating reactors. Specifically, the email, which was courtesy copied to (b)(7)(C) and other staff members, conveyed that (b)(7)(C) supported the RAIs, but questioned the process for issuing RAIs outside of a licensing action and how to handle the response from the licensee. (b)(7)(C) wrote,

> I challenged the staff on what process would apply to this kind of review. (After RAI issuance what is the next step? How are we documenting the technical review given there is no inspection report or licensing action in front of the Commission? What are we producing – an SER? What do we do if we do not agree with the licensees' current situation? What is the criteria for determining financial qualification – the "line in the sand" as it were?) There does not appear to be a documented process for this kind of activity....

On June 5, 2013, (b)(7)(C) provided the draft RAI to (b)(7)(C) (b)(7)(C) (b)(7)(C). This time, however, after (b)(7)(C) informed Entergy about the draft RAI, the licensee contacted (b)(7)(C) and (b)(7)(C) on June 6, 2013, to express a concern and requested to speak with them about this matter in person the following week because they were already planning to visit NRC that week about a different matter. [Investigative Note: The version of this draft RAI that OIG reviewed did not include any concurrences.]

On June 6, 2013, (b)(7)(C) sent an email to DORL and DIRS staff concerning the disposition and issuance of RAIs regarding financial qualifications. The email stated, "in seeking clarity on the most applicable process in which we will ultimately disposition the issues associated with the proposed RAIs and to ensure alignment with DIRS management (also DORL management) and the path forward, I am requesting that you hold the proposed RAIs for now."

On June 11, 2013, Entergy representative (b)(7)(C) visited NRC headquarters and met with (b)(7)(C) and (b)(7)(C) to convey his company's concerns that the followup RAI would have a negative impact on the company.

The hold on financial RAIs continued within NRR as (b)(7)(C), (b)(7)(C) (b)(7)(C) (b)(7)(C), worked to develop a policy concerning the use of RAIs for financial information requests.

In March 2015, NRR issued "Interim Staff Guidance – Reviewing and Assessing the Financial Condition of Operating Power Reactor Licensees, including Requests for Additional Information" to clarify NRC's process for reviewing financial conditions of, and financial concerns about, currently operating power reactor licensees. According to the document, this interim staff guidance (ISG) is intended to supplement NRC financial review guidance in NUREG-1577. The ISG describes NRC's authority for requesting financial information from licensees, states that RAIs may be used for this purpose, and defines the process for internal review. The ISG addresses

A. Level of review – identifying initial issues of concern and confirming accuracy of preliminary sources of information.
B. Criteria to determine whether RAIs should be issued per 10 CFR 50.33(f)(5) – analysis of preliminary source information.
C. Staff peer review and management review.
D. Information to be requested by staff.
E. Staff analysis – criteria for evaluating information provided by licensees.
F. Closeout and disposition following staff analysis of licensee response to RAIs.

In July 2016, NRR provided OIG with the results of its assessment of four sets of financial RAIs that were generated during the 2013 timeframe. One set of RAIs had been transmitted to the licensee (Vermont-Yankee) and three sets (Entergy, (b)(7)(C) (b)(7)(C) and Exelon) were not transmitted. According to (b)(7)(C), the staff analyzed the four sets of RAIs using the March 2015 ISG and concluded that no further action was required relative to any of the four sets of RAIs.

NRC's analysis, "Disposition of RAIs Generated by Staff in 2013 – Financial Status of Licensees," dated July 5, 2016, describes the basis underlying each set of RAIs and the rationale (i.e., ISG criteria) for concluding no further action was warranted, noting for each set of RAIs "there exists no requirement to meet [financial qualification] requirements" and "the potential for significant, long-term chronic impacts to revenue, net income, or other sources of funds" could not be assumed or derived from the information used as the basis for the RAI.

Interviews

(b)(7)(C) told OIG that after reviewing Entergy's 10-K filings with the SEC, she learned there was an impairment listed for Vermont Yankee. (b)(7)(C) stated that the impairment ("the plant was not producing enough cash flow to cover its operational cost") raised questions as to whether Entergy was meeting the financial qualification requirement, so she decided to draft an RAI to Vermont Yankee, which was issued to the licensee on March 20, 2013. (b)(7)(C) stated that Entergy responded May 2013 with its financial projections, which revealed poor results. (b)(7)(C) developed a followup RAI for Entergy covering multiple plants because she believed other Entergy plants could have been impacted. [Investigative Note: OIG reviewed the RAI, which cited as its rationale (1) information published by the Energy Information Administration on January 9, 2012, describing a decline in wholesale energy prices, and (2) information from an Entergy SEC 10-Q[2] statement describing the impact of the economic downturn and negative trends in the energy commodity markets.]

On June 5, 2013, (b)(7)(C) provided the draft RAI to (b)(7)(C) (b)(7)(C) (b)(7)(C). She said that typically (b)(7)(C) would contact the licensee to alert them of a forthcoming RAI. However, (b)(7)(C) claimed that before the draft RAI was issued, a representative from Entergy contacted NRC management to question the RAI. (b)(7)(C) stated that the following day, (b)(7)(C) sent an email to the staff to place the RAIs on hold.

(b)(7)(C) said she was told the RAI had not been issued because the process for issuing RAIs was unclear and she did not have a good basis for issuing the RAIs.

Both (b)(7)(C) and (b)(7)(C) told OIG that (b)(7)(C) RAIs did not originate via the usual process. Typically, RAIs come through the division as part of a license amendment request from the licensee. Usually a licensing action is submitted by the licensee and NRC issues RAIs in response. In these instances, however, there was not an actual licensing action or amendment sent from the licensee; instead, NRC's

[2] The SEC form 10-Q is a comprehensive report of a company's performance that must be submitted quarterly by all public companies to the SEC.

financial review group initiated its own review. The PMs said that it is common practice for PMs to contact the licensee by telephone or email before a formal RAI is issued "just to ensure that the licensee understand[s] what the questions are and minimize rework." If the licensee does not need further clarification, the RAI is issued formally, requesting the licensee to respond, typically within 30 days.

(b)(7)(C) said when he received the draft RAI for the other Entergy plants, he intended to handle it in the same manner as he had for the Vermont Yankee RAI, but (b)(7)(C) sent an email instructing DORL staff to hold off on sending RAIs to the licensee. (b)(7)(C) stated (b)(7)(C) wanted to "understand our process, understand what we're asking, understand the outcome, and the expected outcome" of issuing the RAIs outside of a licensing action.

(b)(7)(C) Financial Analyst, DIRS, told OIG that in the course of doing business, financial analysts keep informed about the industry by monitoring public information such as newspapers and industry newsletters. By doing this, the financial analysts are able to verify the accuracy of the information and also determine if the information could potentially harm a licensee's "ability to either build, operate or eventually decommission a plant because the licensee should have the financial resources." (b)(7)(C) explained that it is rare for financial analysts to ask a question outside of a licensing action and said that in his 17 years at NRC, he may have "done that twice maybe, if that many times, where we simply saw something in the paper, asked a question and get an answer."

(b)(7)(C) said that (b)(7)(C) (b)(7)(C) (b)(7)(C). He could not recall the specifics of the RAIs, but said he spoke to (b)(7)(C) to get a better understanding and felt (b)(7)(C) reasoning was acceptable. (b)(7)(C) was unsure why he did not concur on the RAI issued to Vermont Yankee on March 20, 2013, which showed (b)(7)(C) concurred as the acting (b)(7)(C) on March 18, 2013. (b)(7)(C) said he may have been out of the office and (b)(7)(C) may have been acting.

(b)(7)(C) told OIG that (b)(7)(C) called him and told him that the staff was considering issuing RAIs for Fitzpatrick, Indian Point, and Pilgrim. (b)(7)(C) did not voice his concerns to (b)(7)(C) but spoke to his management, including (b)(7)(C), (b)(7)(C) (b)(7)(C) for all of Entergy, concerning the RAI for the Entergy plants and questioning the basis for the RAI. (b)(7)(C) did not recall receiving a copy of the draft RAI from (b)(7)(C) but said that there were concerns with the draft RAI, if received, because if other merchant fleets in the industry were not receiving a

similar RAI on the same day with the same wording, there could be a "significant unintended consequence."

(b)(7)(C) contacted (b)(7)(C) and (b)(7)(C) on June 6, 2013, to voice his concerns. (b)(7)(C) told (b)(7)(C) that he would be at the NRC and requested a "drop-in" meeting to discuss the draft RAI. On June 11, 2013, (b)(7)(C) met with (b)(7)(C) (b)(7)(C) and another staff member for approximately 15 to 20 minutes. During the meeting, (b)(7)(C) said he reiterated the concerns and discussed the decommissioning trust process, which is a clear and established process when submitting financial information. However, (b)(7)(C) believed that Entergy was being singled out and the nature of the questions were not being driven by process because typically Entergy would have something before the agency (e.g., a license amendment or relief request) for an RAI to be issued. (b)(7)(C) said the meeting was very short and there was no indication of a disposition, and there was no further communication on the matter after the meeting. Although he did not try to persuade the NRC from issuing the RAIs, he felt he influenced the staff to better understand where the concern was coming from and why.

(b)(7)(C) told OIG that normally when the agency "asks a question, an RAI, it's usually in the context of a licensing action put before the Commission." He said the licensees come to the Commission and then request NRC to take an action (e.g., issue an amendment, issue a license, request for an exemption). In the process of reviewing that application, NRC may have the need for more information, and uses an RAI to ask the question. In this case, he said, there was no licensing action before the Commission. Instead, the staff had a concern and wanted to ask the licensee for information to help disposition this concern. It was unclear to (b)(7)(C) what NRC would do with the response because there was no license to be issued or safety evaluation report to come of it. (b)(7)(C) said, "It was very unclear what the process was for dealing with this because it was out of the norm."

(b)(7)(C) said the RAI questions were developed when he was on rotation, but (b)(7)(C) requested approval to send the RAI to the licensee after (b)(7)(C) returned. (b)(7)(C) believed that the questions were reasonable, but was concerned about the process. Nevertheless, he said he concurred on the draft RAI and it was forwarded to the PM in the licensing organization who, in turn, contacted the licensee to inform them of the draft RAI.

According to (b)(7)(C), after (b)(7)(C) spoke to NRR management and questioned the regulatory basis for the draft RAI, a decision was made by (b)(7)(C) and (b)(7)(C) to put a hold on all draft RAIs that were developed to address the process-related concerns (e.g., What process are we in? What is the regulatory basis?) before the questions are issued to the licensee. (b)(7)(C) sent an email to the PM as well as the NRR staff to put

a hold on the draft RAIs for the moment. The following week, (b)(7)(C) had a drop-in meeting with (b)(7)(C) for approximately 10-15 minutes to discuss his concerns.

(b)(7)(C) told OIG that (b)(7)(C) sent a detailed email on May 31, 2013, to him and (b)(7)(C) that discussed a set of RAIs that were being developed for Entergy as well as other facilities. (b)(7)(C) stated (b)(7)(C) was concerned with the process, basis, and overall handling of the RAIs. (b)(7)(C) said (b)(7)(C) wanted to pause before issuing the RAIs to figure out a process for this type of RAI. (b)(7)(C) said he agreed with (b)(7)(C) approach.

(b)(7)(C) said (b)(7)(C) requested a meeting with (b)(7)(C) and (b)(7)(C) a week after the RAIs were placed on hold. (b)(7)(C) recalled that (b)(7)(C) told (b)(7)(C) that if an appropriate question needed to be asked, it would be asked. (b)(7)(C) said while there could have been an appearance that (b)(7)(C) was trying to influence the staff not to issue the RAIs, the meeting did not influence his decision to put the draft RAIs on hold.

(b)(7)(C) said that interim staff guidance was generated as a part of the initiative to better clarify and implement the process. He said the RAIs that were placed on hold would be reviewed using the newly developed process and a determination will be made as to whether or not to issue the RAIs.

(b)(7)(C) told OIG that he learned of the RAIs when he received a call from (b)(7)(C) who wanted to discuss the RAIs with NRR management because he had some questions and concerns. Prior to that phone call, (b)(7)(C) said he had not seen the RAIs developed for Entergy.

(b)(7)(C) said during the meeting, he and (b)(7)(C) listened to (b)(7)(C) concerns about the RAIs and the possible impacts of these RAIs on the company's stock prices as well as how shareholders may perceive what was going on with the company and/or the general market impact. (b)(7)(C) told (b)(7)(C) that although he was mindful of (b)(7)(C) concerns, they were not of primary concern to NRC. He said that if the staff identified a safety issue with their facility or an issue with their licensing basis, the RAIs would be sent. (b)(7)(C) told (b)(7)(C) he would review the RAIs and go from there. (b)(7)(C) indicated that at no time during the meeting with (b)(7)(C) did he feel he was being influenced not to issue the RAIs to Energy.

After the meeting with (b)(7)(C) (b)(7)(C) said that he met with (b)(7)(C) and (b)(7)(C) to review the draft RAI to Entergy to determine what was being asked. Based on their review, it appeared that the RAI was general in nature because it referenced a Department of Energy Web site link to a report that discussed declining energy prices

across the country. (b)(7)(C) said that the review prompted questions about the process for issuing the RAIs outside of a licensing action.

(b)(7)(C) said the regulatory basis for issuing the RAIs was not clear and he believed that until the staff could document a clear basis of what was being asked, how that information was going to be used, and the connection to safety, the RAIs should be placed on hold. (b)(7)(C) said that the regulation (NUREG-1577) "is not precisely defined as some other areas in our regulatory framework."

(b)(7)(C) told OIG that the current process for issuing RAIs outside of a licensing action is ad hoc, and he requested that the staff develop a process, implement through interim guidance, make revision to the NUREG, and put it out for public comment to receive feedback.

(b)(7)(C) said the decision to place the RAIs on hold was made by (b)(7)(C) and (b)(7)(C) with his support and agreement.

Former NRC-Chairman MACFARLANE told OIG that on December 19, 2013, NRR Financial Analysis and International Projects Branch staff met with her to discuss financial qualifications of nuclear power plants. She did not recall making a statement that the staff should look into the Entergy situation and should issue the RAIs, but she said the staff may have interpreted her questioning of the RAIs as giving direction to issue the RAIs to Entergy. MACFARLANE indicated that she could not give the staff direction to issue RAIs because giving direction to the staff is accomplished through a formal process with the consensus of the other Commissioners. MACFARLANE stated that she could only give the staff direction concerning personnel issues (i.e., training) and/or reorganization issues.

(b)(7)(C), an attendee at the briefing, said that he may have stated to a staff member that the Chairman "is only one Commissioner." (b)(7)(C) could not remember his exact statement to any staff member, but he acknowledged that the former Chairman could not give the staff instruction without a Staff Requirements Memorandum, which the staff never received.

(b)(7)(C) told OIG that (b)(7)(C) tasked him in the May/June 2013 timeframe to develop and clarify a process for issuing RAIs outside of a licensing action. (b)(7)(C) indicated that the process was developed throughout 2014 and the final document was published for transmittal in the Federal Register March 2015 in the form of an ISG. According to (b)(7)(C), the process provides a roadmap for staff to determine if an RAI is warranted under 10 CFR 50.33(f)(5). (b)(7)(C) told OIG that the process will determine if an RAI

should be developed, the criteria used by staff, the questions that would be asked, how the information would be evaluated, and what staff would do with the information.

(b)(7)(C) provided OIG with "Disposition of RAIs Generated by Staff in 2013 – Financial Status of Licensees," dated July 5, 2016, which assessed four sets of RAIs drafted by staff between March and June 2013. The assessment reflected the outcome of the staff's application of the ISG, concluding that no further action was needed with regard to any of the RAIs.

Because OIG could not substantiate that the NRC staff was inappropriately influenced to halt the June 2013 draft RAI, and the staff has developed a process through an ISG when issuing RAIs outside of a licensing action, it is recommended that the case be closed to the files of this office.

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Case File 14-011 Magnum

OIG (b)(7)(C)	OIG (b)(7)(C)	(b)(7)(C)	OIG (b)(7)(C)	OIG (b)(7)(C)	OIG	OIG
(b)(7)(C)	(b)(7)(C)	(b)(7)(C)	(b)(7)(C)	J. McMillan	D. Lee	H. Bell
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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

OFFICE OF THE
INSPECTOR GENERAL

August 14, 2018

MEMORANDUM TO: Concur: Case Closed
Rocco J. Pierri
Assistant Inspector General
for Investigations

THRU: (b)(7)(C)
Team Leader, (b)(7)(C)

SUBJECT: CYBER SECURITY MILESTONE 8 AT PILGRIM NUCLEAR POWER STATION (OIG CASE NO. 18-014)

Allegation

The Office of the Inspector General (OIG), U.S. Nuclear Regulatory Commission (NRC), initiated this investigation based on an allegation from three Special Interest groups: The Town of Duxbury Nuclear Advisory Committee, Pilgrim Nuclear Power Station (PNPS) Watch, and Union of Concerned Scientists. These groups requested the OIG to investigate the timing of NRC's license amendment that allowed Entergy Nuclear Operations, Inc. (ENTERGY), to postpone the December 15, 2017, deadline for completing the Cyber Security Milestone 8 (Milestone 8) at PNPS until December 15, 2020. The NRC approved the license amendment on the December 15, 2017, deadline day. According to the allegers, the NRC staff might have revealed pre-decisional information by tipping off ENTERGY that they need not worry about the December 15, 2017, deadline because NRC would issue a last minute amendment.

Findings

OIG did not find evidence that the NRC revealed pre-decisional information to PNPS during the license amendment request (LAR) process. While the approval of the LAR

did occur on the exact due date of December 15, 2017, for completing Milestone 8, OIG found no indications of any inappropriate interactions between the NRC and ENTERGY staff.

Basis for Findings

Nuclear power facilities use digital and analog systems to monitor, operate, control, and protect their plants. Licensees are required to protect such systems and networks from cyber-attacks that would act to modify, destroy, or compromise the integrity or confidentiality of data or software; deny access to systems, services, or data; and impact the operation of systems, networks, and equipment. NRC's cyber security rule is a performance-based programmatic requirement that aims to ensure that the functions of digital computers, communication systems, and networks associated with safety, important-to-safety, security, and emergency preparedness are protected from cyber-attacks. Licensees are following a two-phased approach for implementation of the cyber security rule requirements, which includes a cyber security plan. NRC developed inspection procedures to verify that licensees are implementing their programs in accordance with the cyber security rule. Implementation and inspections of the first phase, Milestones 1-7, have been completed. The final phase, Milestone 8, relates to the full implementation of a licensee's cyber security plan which includes installation and monitoring of security controls to protect against cyber-attacks. The NRC Milestone 8 cyber security inspections began in 2017 and the staff expects to have all plants inspected within the next few years.

OIG learned that the NRC inspected Pilgrim's implementation of Milestones 1 through 7 and found them acceptable. On March 30, 2017, PNPS submitted a LAR proposing a change to the PNPS Cyber Security Plan Milestone 8 full implementation date as set forth in the Cyber Security Plan Implementation Schedule. The NRC accepted the LAR, and thereafter began its safety review.

Approximately 8 months later, on November 15, 2017, the cybersecurity technical staff in the Office of Nuclear Security and Incident Response (NSIR) provided its safety evaluation for PNPS's LAR to the Office of Nuclear Reactor Regulation (NRR) Project Manager (PM). No formal requests for additional information (RAIs) or informal technical clarifications were required for NSIR's review. The NRR PM then put the amendment package together and provided it to the NRC Office of the General Counsel (OGC) for a legal review on November 28, 2017. Thereafter, OGC had concerns and engaged the staff to resolve. Multiple meetings on November 29th, December 7th, and December 13th occurred between OGC and the staff to address OGC's questions and comments. Over this 2-week period, the NRC expeditiously reviewed and approved the safety evaluation report that provided the basis for approving the license amendment request. On December 14, 2017, OGC provided its no legal objection decision to the

NRR PM; and on December 15, 2017, NRC issued the amendment. Also, in early December, ENTERGY staff at the plant and in the ENTERGY Corporate office began questioning the status of the LAR. Thereafter, the senior engineer for regulatory assurance, (b)(7)(C), began requesting updates from the NRR PM who replied that OGC and other NRC staff were working through concerns. On December 14, 2017, which was the day before the deadline, (b)(7)(C) provided a document to PNPS' Information Technology manager, (b)(7)(C) describing the actions PNPS had taken and would take to address Milestone 8. This document was going to be the base document for a Condition Report to address the potential violation for non-compliance with its license in the event the LAR would not be approved by the NRC. Ultimately, the NRC approved the LAR on December 15, 2017.

(b)(7)(C), (b)(7)(C) told OIG that he remembered speaking approximately once per month with (b)(7)(C) regarding the status of the LAR. (b)(7)(C) stated that PNPS was getting nervous, especially in late November and early December 2017 since the December 15, 2017, due date was approaching. (b)(7)(C) recalled receiving NSIR's safety evaluation input in November 2017. (b)(7)(C) stated that no RAIs were submitted to ENTERGY for this LAR review. He also stated that he did not coordinate any informal technical clarifications with ENTERGY during NSIR's review. He then put the amendment package together and provided it to OGC for a legal review on November 28, 2017. (b)(7)(C) stated that OGC had a legal objection with some of the wording in the safety evaluation. He stated that several internal meetings were held to resolve OGC's concerns. (b)(7)(C) did not know when the amendment would be approved until OGC provided its "No Legal Objection" (NLO) concurrence on December 14, 2017. (b)(7)(C) successfully issued the LAR acceptance letter on the next day, December 15, 2017.

(b)(7)(C), the (b)(7)(C) in (b)(7)(C) (b)(7)(C) told OIG he attended a Nuclear Energy Institute meeting in February 2017, in which industry presented an approach for complying with the Cyber Security Program Milestone 8 for plants that announced they were decommissioning in the next few years. During this meeting, (b)(7)(C) stated that he listened and replied that submitting a LAR and requesting extension of the Milestone 8 date seemed reasonable and would be reviewed on the merits of licensees' LARs as described in NRC's LAR process. (b)(7)(C) stated that in 2017, he informed the licensees the NRC could not guarantee the LARs would be done by the due date, and that if they were not fully implemented, they would be in violation.

When PNPS submitted its LAR on March 30, 2017, NRC had 10 similar LARs from other plants. (b)(7)(C) stated that having 11 LARs for the NSIR branch to review before their due dates was challenging. (b)(7)(C) told (b)(7)(C) that if the PNPS request was technically sound, NRC would make every attempt to complete its review in time to

support licensee's due date of December 15, 2017, thus keeping the licensee in compliance with its cyber security license commitment. (b)(7)(C) stated that no RAIs were asked and no technical clarifications were requested from ENTERGY.

[Investigative Note: The Cyber Security Programs were initially approved by the NRC in the 2009 timeframe and placed in licensee's license as License Conditions].

OIG spoke with three OGC Attorneys who were involved in this LAR. They were (b)(7)(C) (b)(7)(C), (b)(7)(C), and (b)(7)(C). They stated that they did not communicate with the licensee. OGC had a legal objection with some of the wording in the safety evaluation report (SER). Several internal meetings were held and the SER was revised each time. On December 12, 2017, (b)(7)(C) sent an email to (b)(7)(C) stating that the completion of Milestone 1 – 7 and the initiation of a few activities in Milestone 8 as the basis of granting an extension was the bare minimum to establish adequate protection against the threat of cyber-attacks. OIG learned that although OGC usually has a 10-day review time, (b)(7)(C) extended the OGC 10-day review time. On December 14, 2017, OGC provided legal review and an NLO concurrence.

(b)(7)(C), the NRC (b)(7)(C) (b)(7)(C) at (b)(7)(C) told OIG that she was not aware of or involved in the process at all. She had no influence on this process since it was a licensing action being coordinated by NRR. (b)(7)(C) did not know why the LAR was approved on the due date.

(b)(7)(C) who was (b)(7)(C) and (b)(7)(C) on (b)(7)(C) told OIG that the LAR went through their "normal process." He said that PNPS was preparing for an NRC special inspection that consumed the majority of his time. (b)(7)(C) stated that (b)(7)(C) was handling the Milestone 8 LAR. As the December due date came closer, he knew that (b)(7)(C) was requesting status updates from NRC's PM. (b)(7)(C) remembered (b)(7)(C) reporting that NRC staff was addressing concerns that OGC had but he was not aware of what OGC's concerns were. He agreed the LAR went down to the last minute; however, he remained optimistic that it would get approved.

(b)(7)(C) (b)(7)(C) at PNPS since (b)(7)(C) told OIG that he was the author of the LAR and PNPS's point-of-contact with the NRC for the LAR. (b)(7)(C) told OIG that he received no pre-decisional information from the NRC. (b)(7)(C) said he was "worried sick" about the LAR not getting approved. (b)(7)(C) was well aware that PNPS would be in non-compliance with its license and did not know what exactly would happen. (b)(7)(C) started communicating with NRC's PM on a frequent basis starting in November 2017 and basically was told that OGC and the NRC technical staff were working through OGC's concerns. (b)(7)(C) decided to prepare a "white paper" describing the technical basis for Pilgrim's Milestone 8 license condition

and his interactions with the NRC. He developed this paper in preparation of a Condition Report that would be required on December 16, 2017, assuming the LAR was not approved. (b)(7)(C) emailed his "white paper" to his supervisor, (b)(7)(C), on December 14, 2017.

[OIG Investigative Note: (b)(7)(C) provided the e-mail, dated December 14, 2017, and attached "white paper" to the OIG].

(b)(7)(C), who is PNPS's (b)(7)(C) (b)(7)(C) told OIG that he is responsible for PNPS's cyber security program. He stated that PNPS submitted an identical LAR as ENTERGY's other plant Palisades Nuclear Plant (Palisades). Both ENTERGY LARs requested to delay implementation of Milestone 8 to December 2020. He added that Palisades has since reversed its position on decommissioning and is currently in the process of implementing Milestone 8. (b)(7)(C) stated that if the LAR for PNPS was not approved, ENTERGY was prepared to provide PNPS the resources to come into compliance to meet Milestone 8. (b)(7)(C) also remembered during an ENTERGY corporate cyber security meeting in New Orleans, on December 5, 2017, his management told him that OGC was holding up the LAR. (b)(7)(C) called (b)(7)(C) for a status update and was basically told the same thing. OGC had concerns with the LAR and the NRC was working through them. (b)(7)(C) was relieved when the LAR was approved and shared with OIG that some parts of Milestone 8 were already implemented.

(b)(7)(C), (b)(7)(C) Cyber Engineer, told OIG (b)(7)(C) (b)(7)(C) (b)(7)(C) told OIG he was aware of the LAR and had no idea if it was going to get approved. He was not sure what would happen since he was not involved in the regulatory aspects of cyber security. However, (b)(7)(C) was confident in PNPS's cyber security program and said he was confident that the plant was safe.

OIG Investigations briefed OIG Audits on this investigation because OIG Audits is planning to conduct an audit in fiscal year 2018 of cyber security at nuclear power plants to include Milestone 8. A copy of this memorandum will be provided to OIG Audits. Because OIG found no indications of misconduct by the NRC staff, it is recommended that investigation be closed to the files of this office.

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